# *2002-2012 Electricity Outlook Report*
## Energy Commission Staff Draft

presented at the

Electricity and Natural Gas Committee Workshop

December 11, 2001

# Finding the Report

- The Workshop Notice, Executive Summary, the full text of the Report and staff's slide presentation can be found on the Energy Commission Web Page
  - open www.energy.ca.gov
  - click on Proceedings
  - click on **2002-2012 Electricity Outlook Report DOCUMENTS PAGE**

- http://www.energy.ca.gov/electricity_outlook/documents/index.html
- Copies are also provided at the table in the Hearing Room foyer

# Today's Agenda

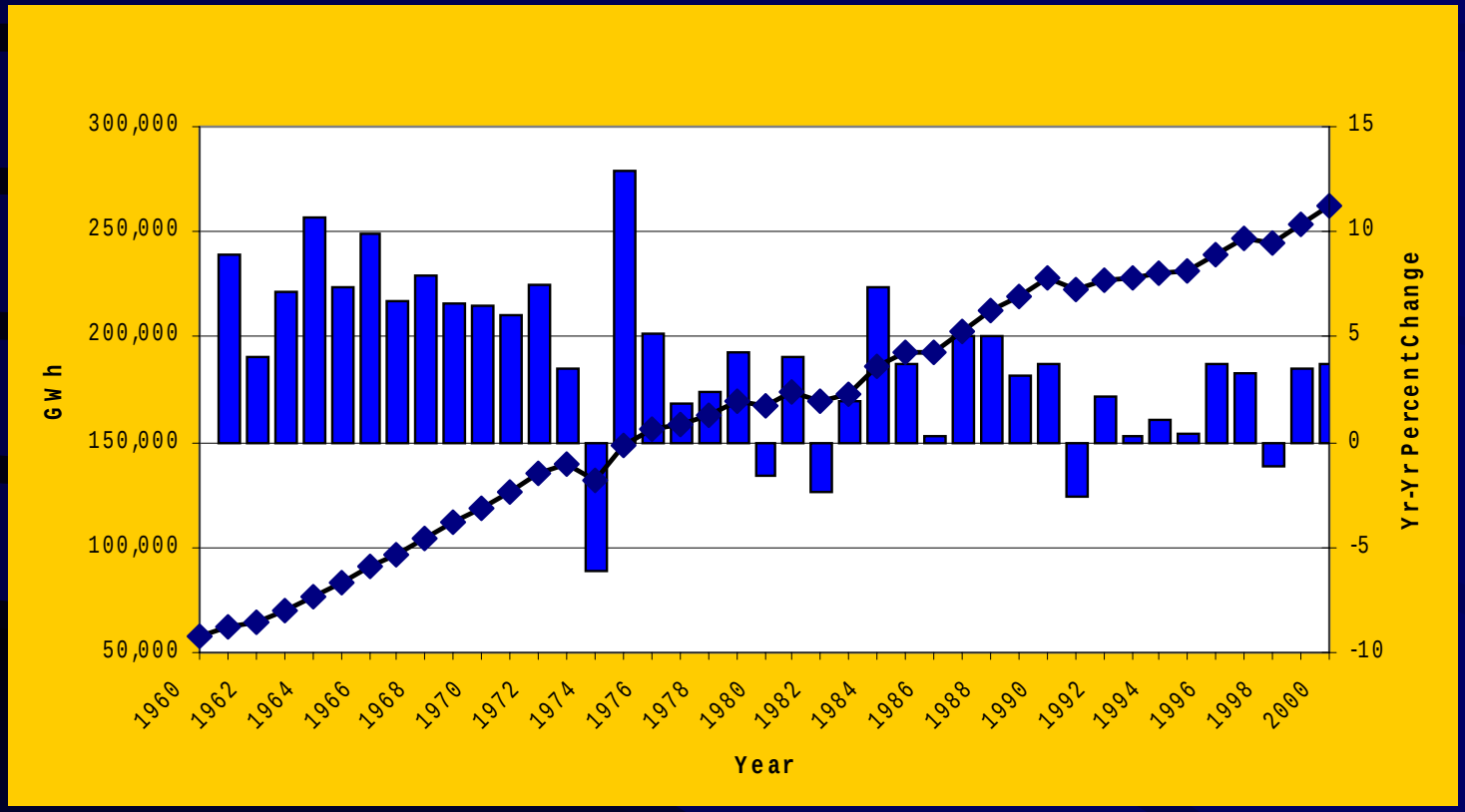
- Housekeeping details
- Committee Opening Remarks
- Staff Presentations ~ 1 hour
  - David Vidaver - demand, market simulations, probabilistic reliability assessment
  - Karen Griffin - sustaining supply adequacy
  - Ross Miller - issues related to retirements, retail rates, demand responsiveness, renewables and licensing
- Public Comments and Presentations ~ 30-90 minutes
- Committee Closing Remarks

# Procedural Details

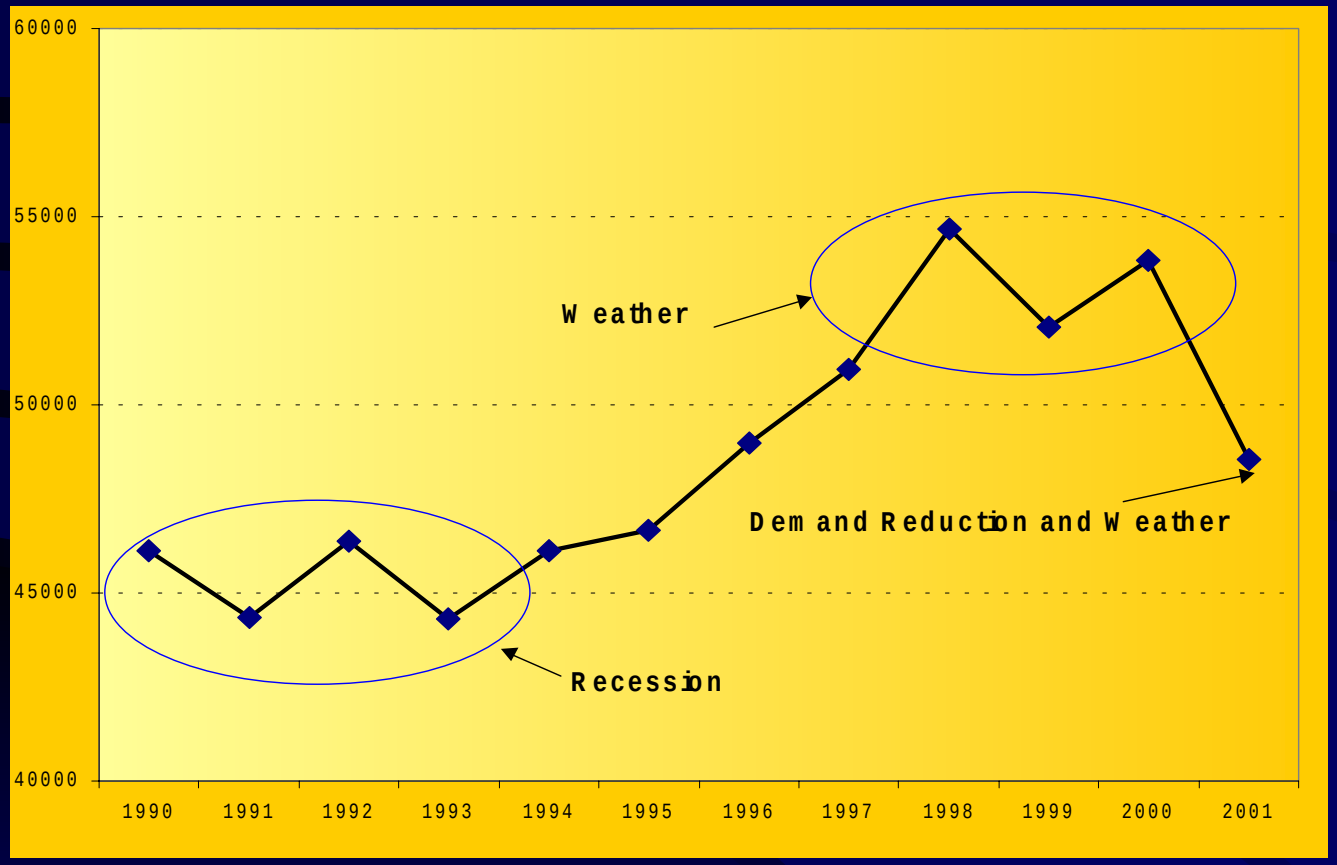
- Purpose and timing of this report:
  - useful to the Governor's Office, Legislature for its next session, and energy industry participants
  - provide information to the California Consumer Power and Financing Authority, which is conducting a public process to develop its Energy Resources Investment Plan.
- Deadline for written comments is Friday, December 21
- The Committee will consider all comments and prepare a final report that will then be proposed for the Energy Commission to consider and adopt at a later date

# California Electricity Demand

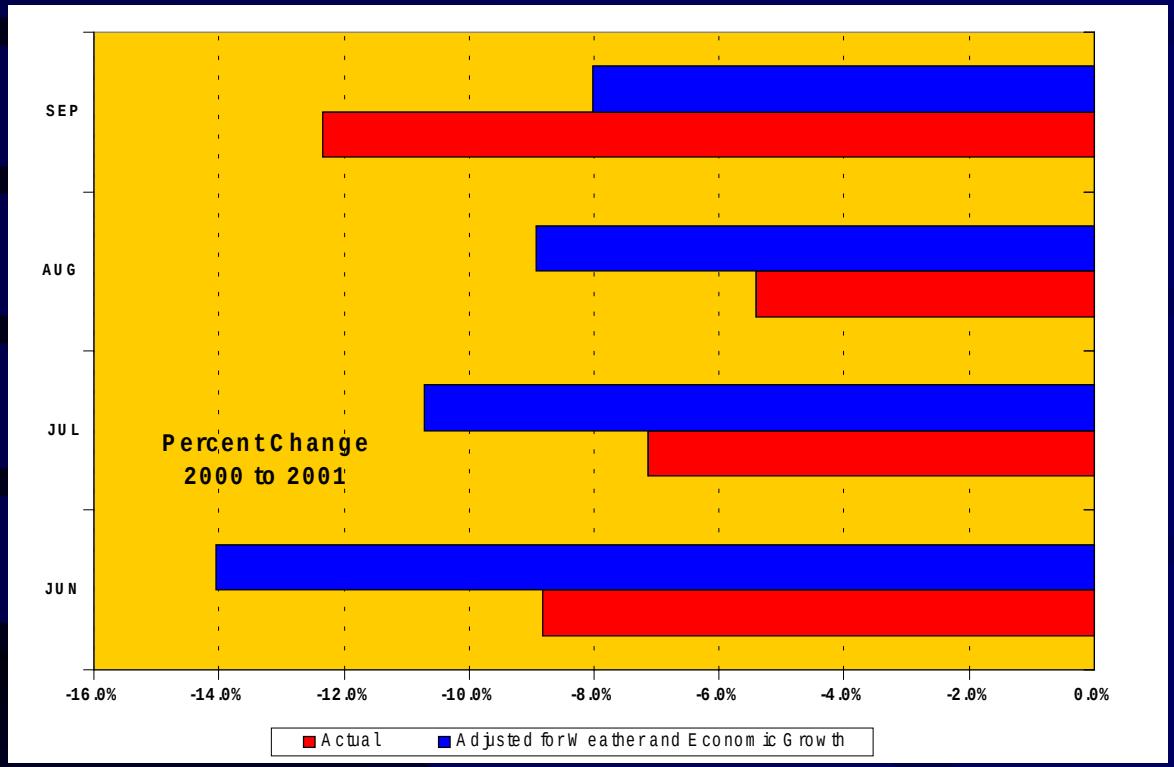
# 1999-2000 was Neither Unprecedented nor Extraordinary



# Peak Demand Influenced by Economics and Weather



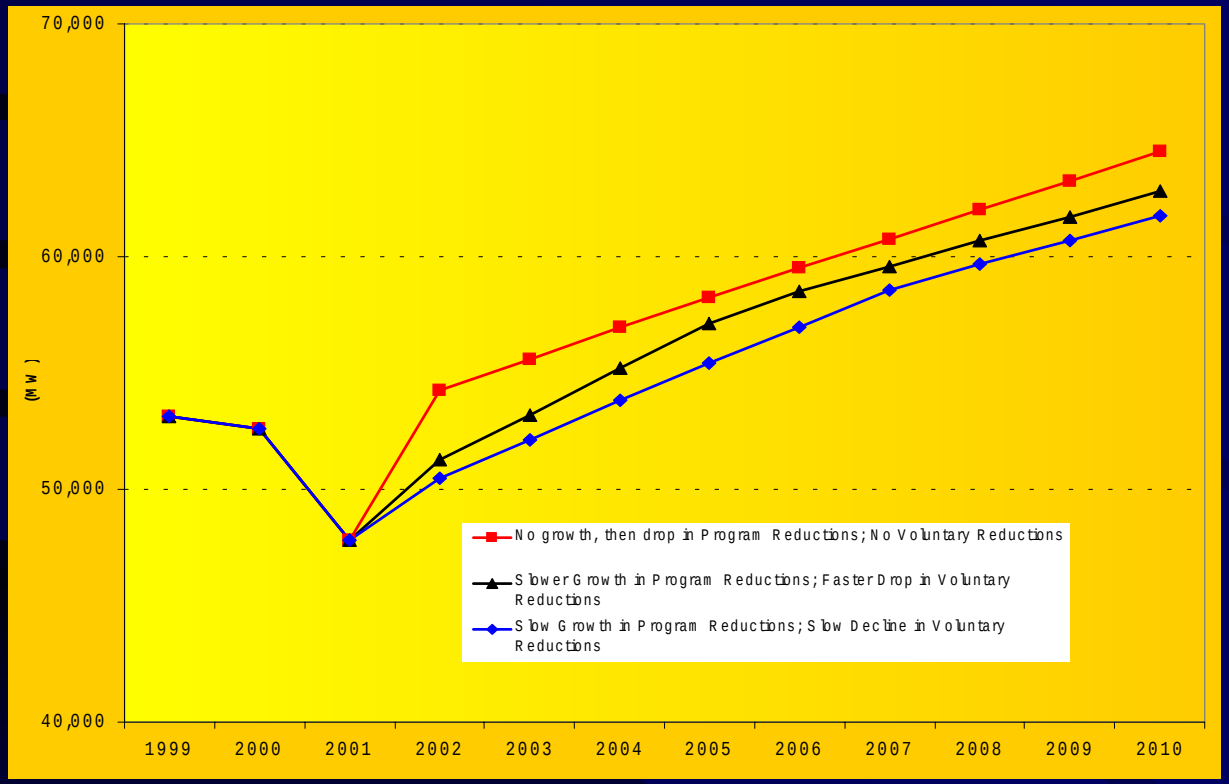
# Summer 2001 Peak Demand Reductions



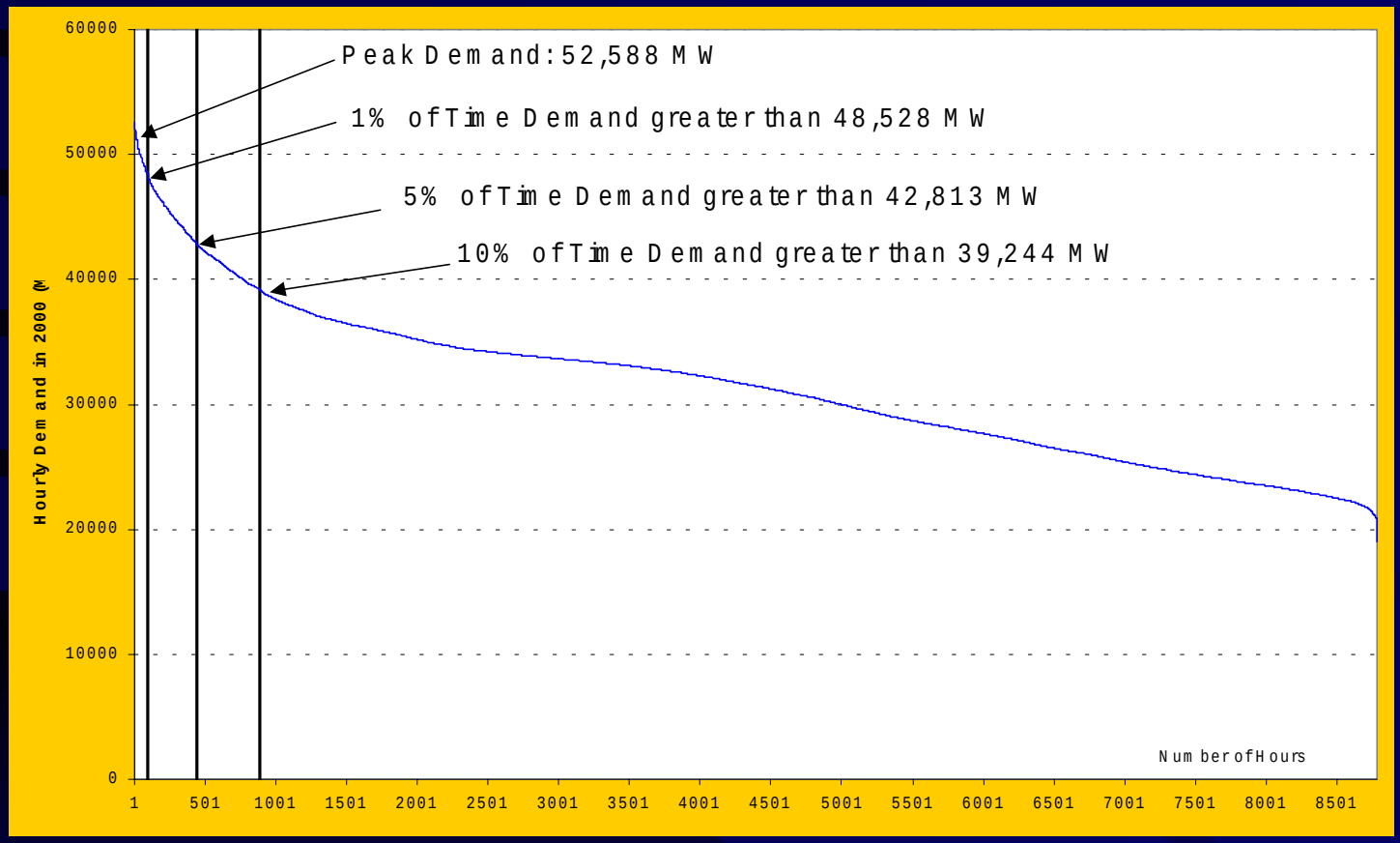
# Factors Contributing to Demand Reduction

- Electricity price increases
- Public awareness of crisis and voluntary conservation
- Demand reduction programs
- 20/20 program
- Slower regional economic growth/September 11th

# California Peak Demand Growth Scenarios



# Demand Near Peak Level in Very Few Hours

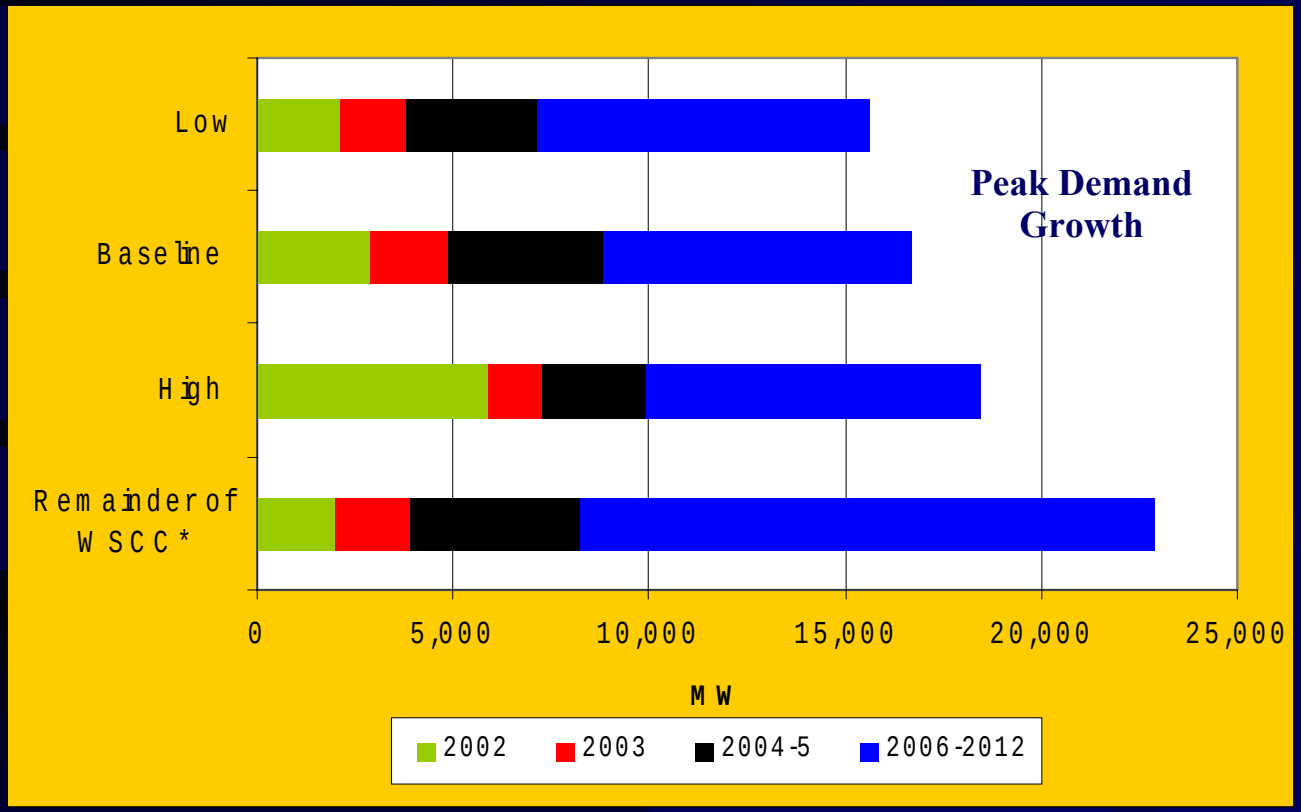


# Estimating Wholesale Spot Prices For Electricity in California and the West

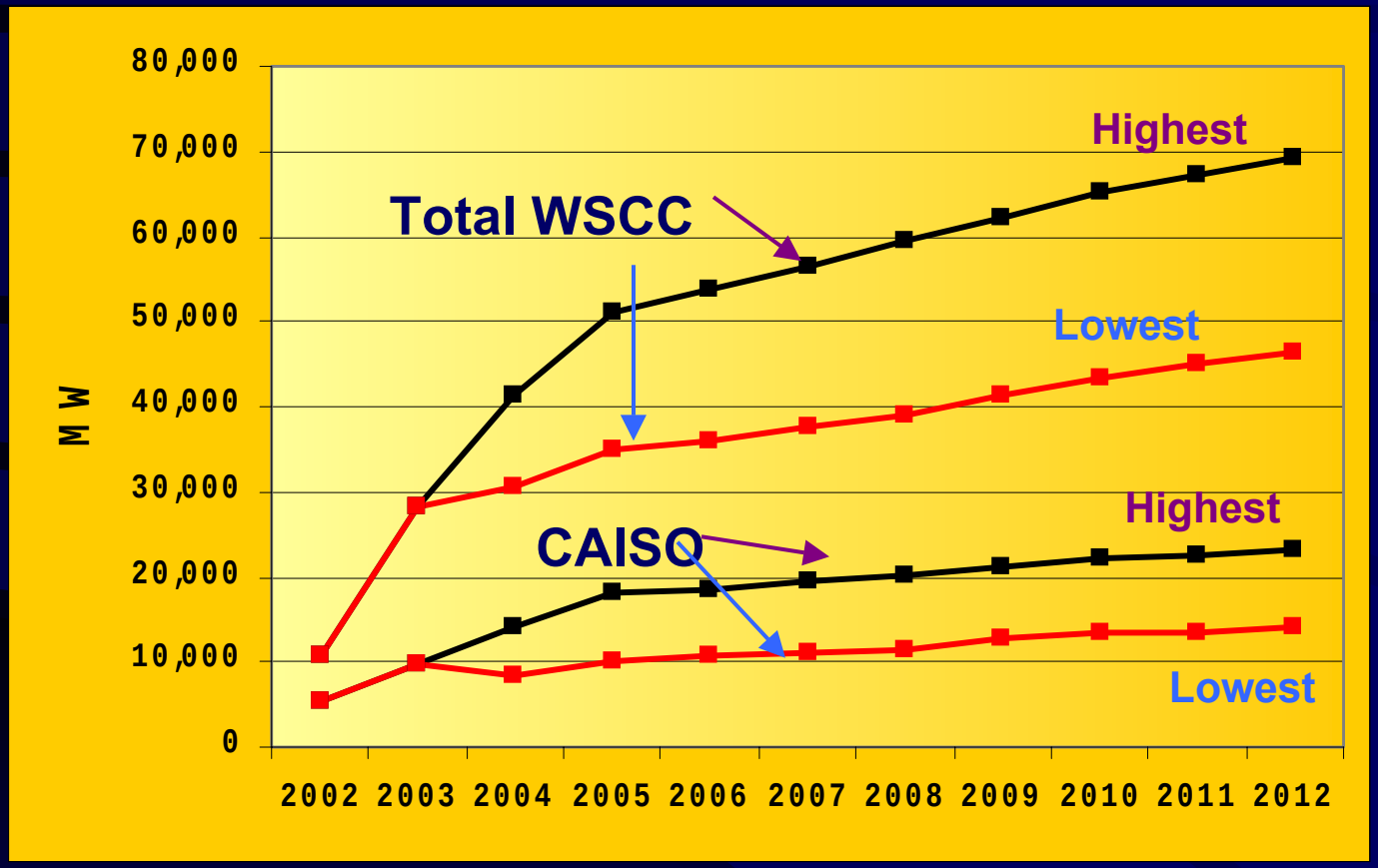
# Simulations of the Wholesale Spot Market 2002 - 2012

- Performed to get estimates of prices, which influence decisions to build new plants and retire old old ones.
- Requires modeling local area demand, operating characteristics of individual power plants, transmission constraints, estimating natural gas and other fuel prices, etc.
- Requires modeling the entire Western U. S.
- Estimated prices are conditional upon the assumptions made regarding market conditions.
    - Demand growth
    - Net capacity additions
    - Degree of market competition
    - Natural gas prices

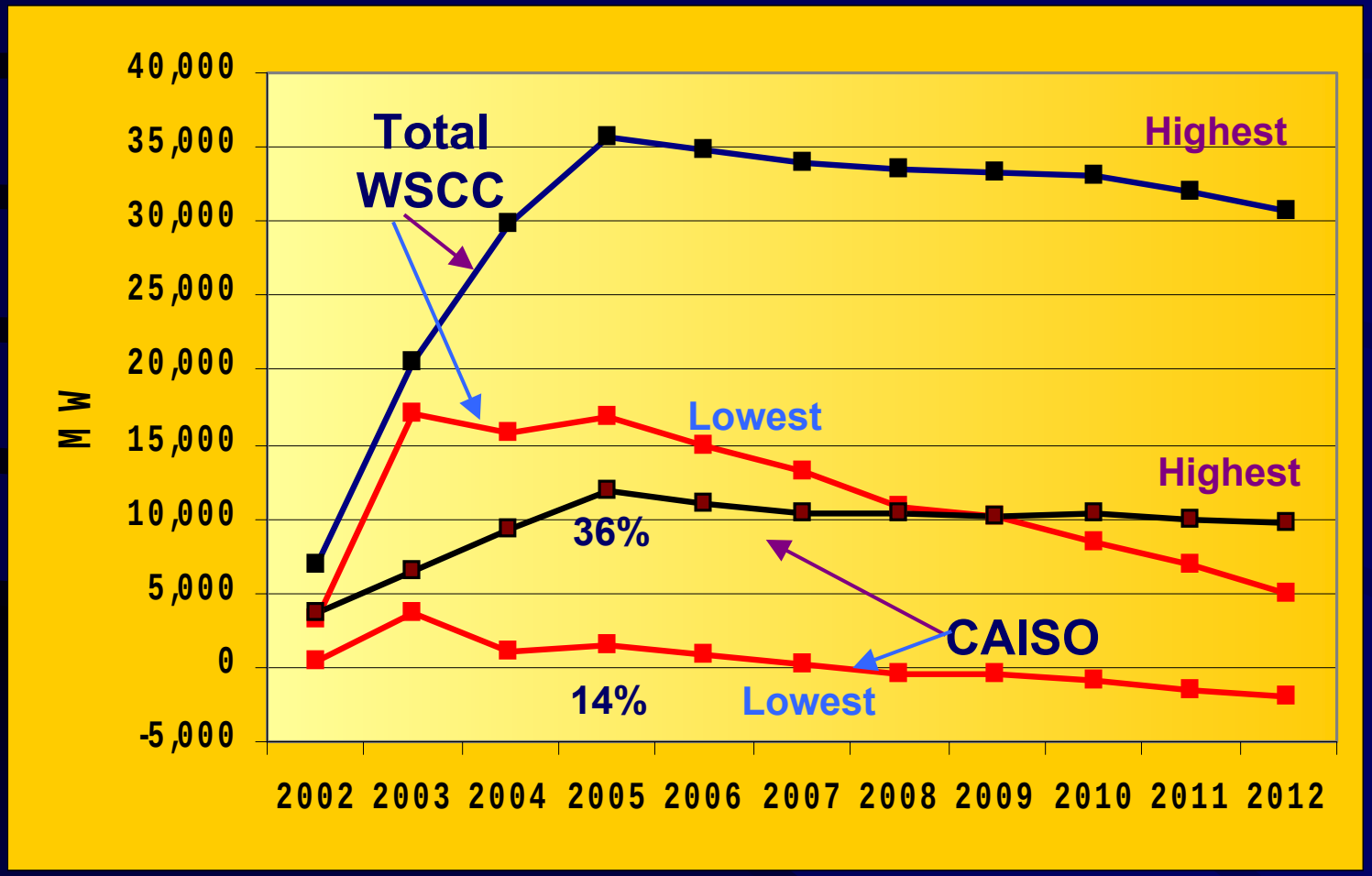
# Three Scenarios for California Peak Demand



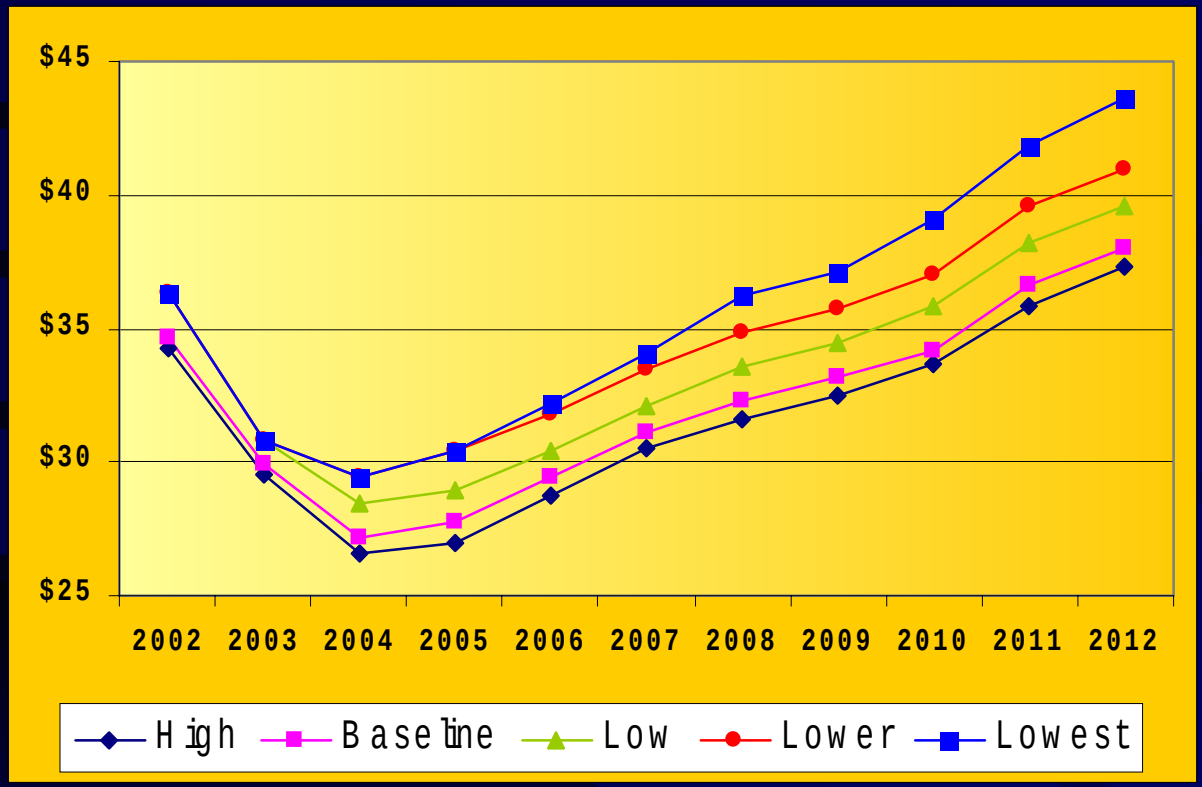
# Bounds For Cumulative Capacity Additions in the Five Scenarios 2001 - 2012



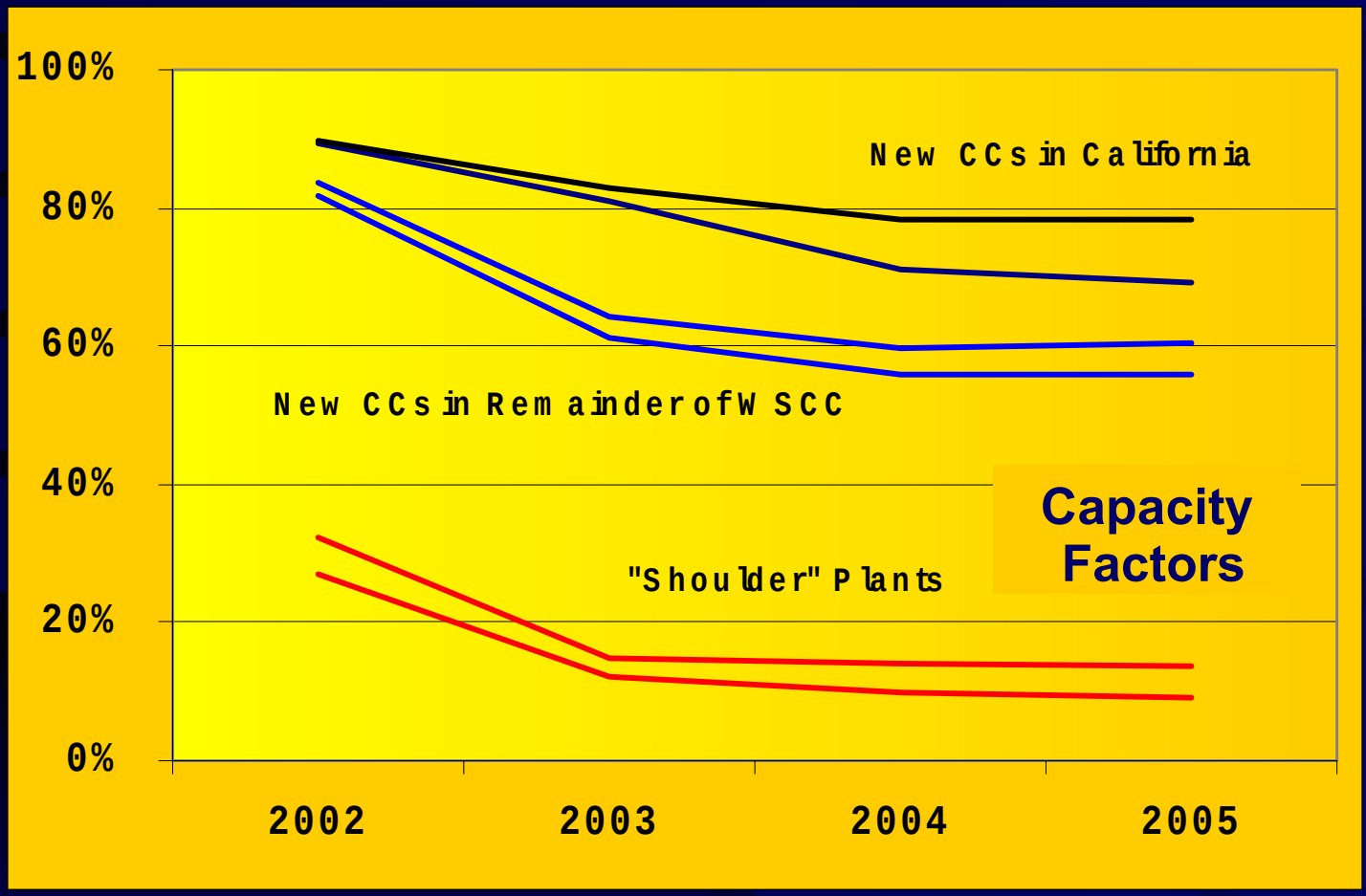
# Bounds For Changes in Reserve Capacity in the Five Scenarios 2001 -



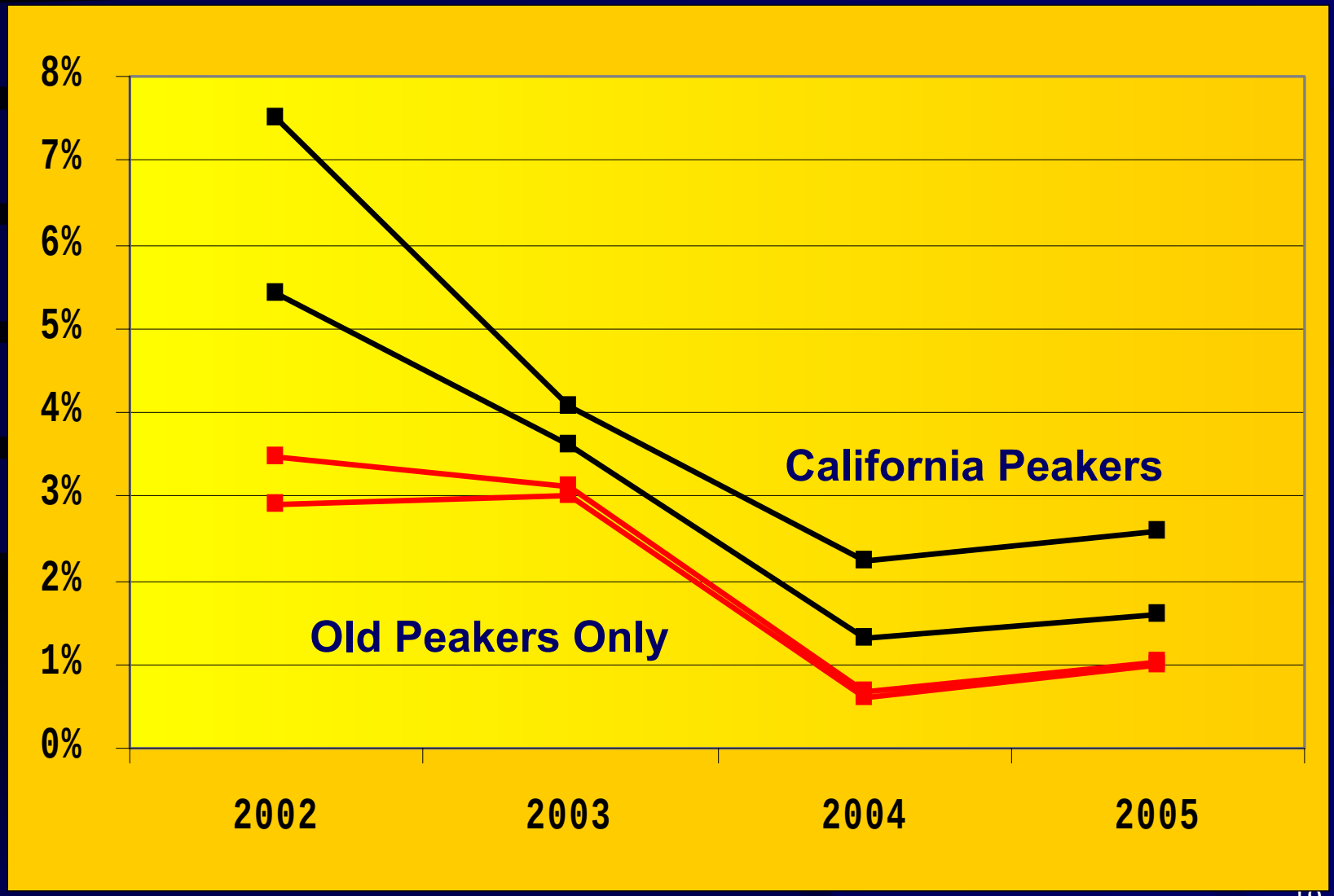
# Average Annual Prices Fall in 2003-2004



# How Much Do New and Existing Plants Run?



# Peaking Plants Run Less Often

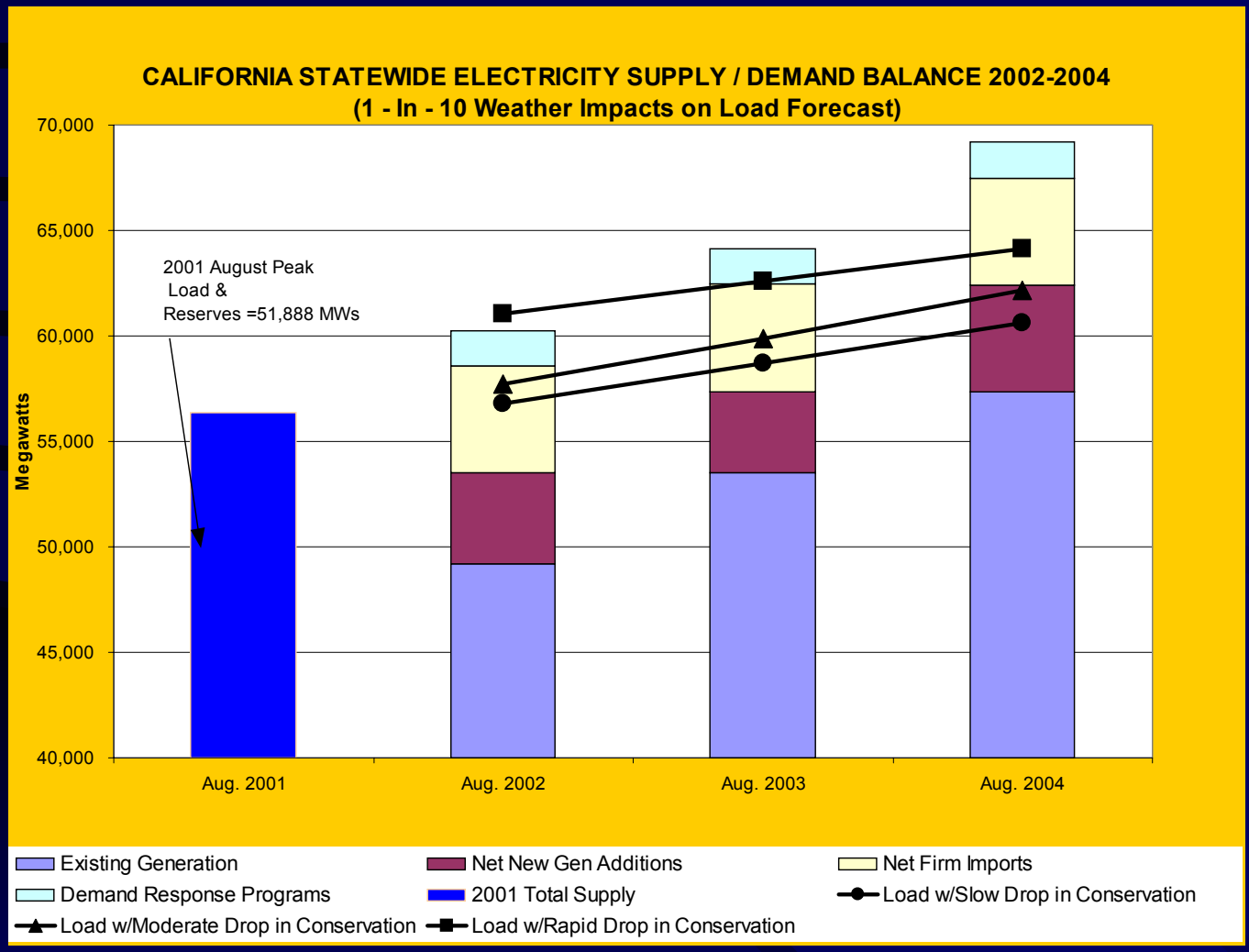


# Conclusions

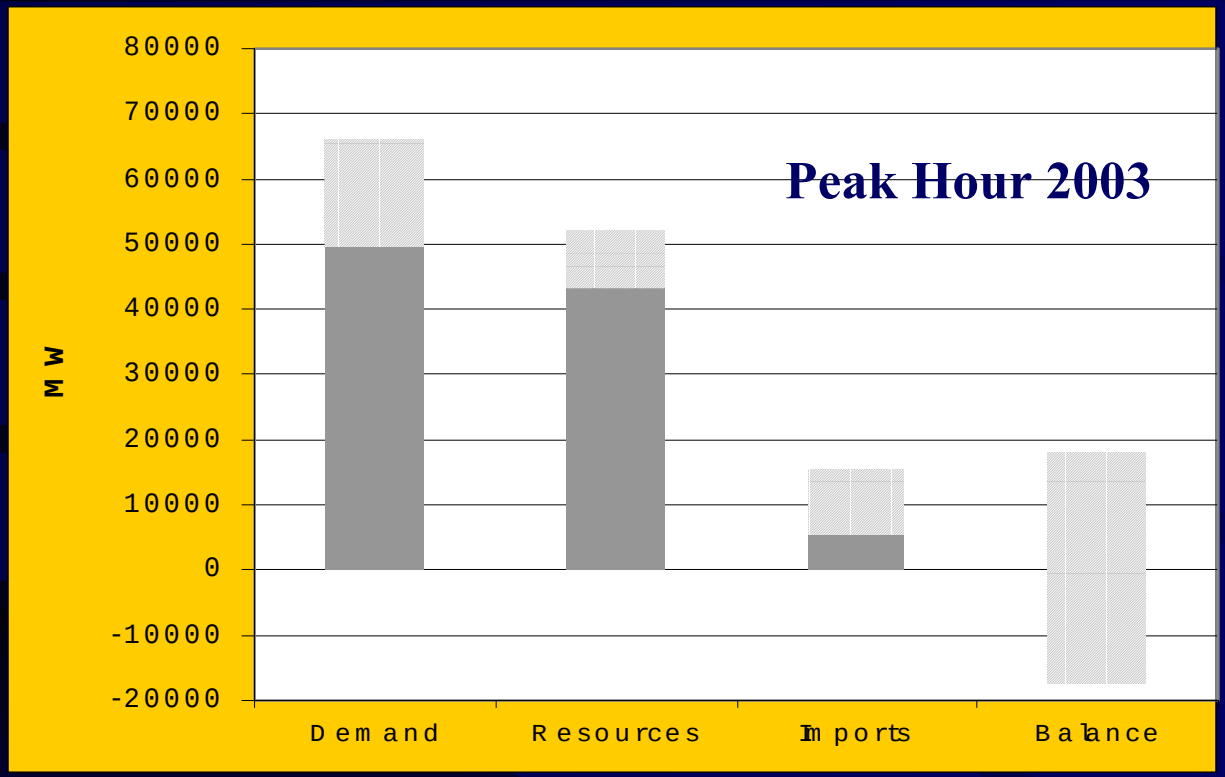
- Prices fall in 2003-2004 and remain low for several years
- New combined cycles are less profitable than hoped for in the long run
- Profitability of existing merchant plants is greatly reduced
- Market is heading for ‘bust’ phase of ‘boom-bust’ cycle
- Simulated prices would encourage consideration of retirement.

# Quantifying the Risk of Capacity Shortages

# Capacity Adequacy Without Uncertainty



# Quantifying the Risk of Capacity Shortages



# Quantifying the Risk of Capacity Shortages

**Demand Reduction Uncertainties**
**Shortage Risks and Maximum Deficits by Transmission Zone**
**Summer Peak Period 2003**

| Transmission Zones | Risks (Percent) | | Maximum Deficit (MW) | |
|---|---|---|---|---|
| | Baseline Scenario | High Load Scenario | Baseline Scenario | High Load Scenario |
| South CA | 1.3 | 4.3 | 1,730 | 5,210 |
| North CA | 0 | 0 | 0 | 0 |
| San Diego | 7 | 17 | 3,030 | 3,540 |
| San Francisco | 13.7 | 11 | 230 | 210 |
| IID | 7.3 | 18.3 | 280 | 310 |
| LADWP | 0 | 0 | 0 | 0 |
| SMUD | 0 | 0 | 0 | 0 |
| CCENT | 0 | 0 | 0 | 0 |

# Findings

- San Francisco, San Diego remain susceptible to curtailment.
- Southern California faces a very small supply adequacy risk. Most shortages are small; reserve margins will not be satisfied, but curtailments will not be necessary.
- High demand growth, increased outage rates, and delays in new capacity increase the risk of shortages during the peak hour in 2003

# Sustaining Adequacy

- Purpose: Motivate timely investment in generation for reliability and stable prices
- Current ad hoc market design won't work
  - Prone to boom and bust construction cycles
  - Excess price volatility
  - Too little generation for workable competition
  - Won't reduce industry concentration to relieve market power

# Overview of Necessary Changes

- Supply-side method to encourage sufficient capacity
- Retail-side increase in price responses and flattening summer demand spikes
- Wholesale market rules to motivate efficient bids and dispatch

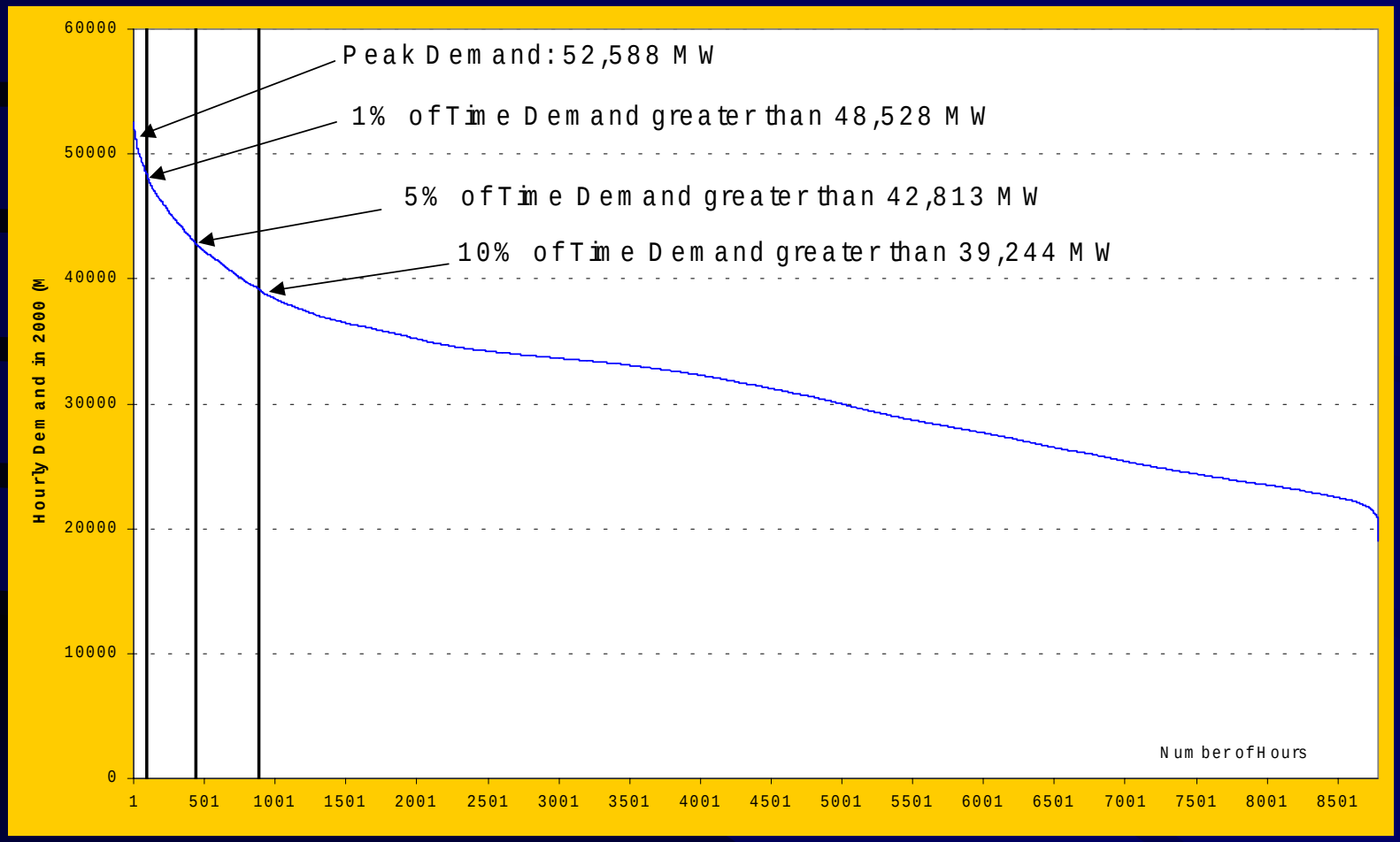
# Four Supply Options

- Pure competition based on energy prices
- Installed capacity requirement on IOU, public power and direct access loads
- State reserves for system net short & A/S
- Market-based capacity payments: could be
  - all generators, bid-based, or new peaking
  - fixed or variable

# Retail Feedback to Generation

- Some real-time response to mitigate price spikes and incent generation when power is of value to consumers
- Use prices, load management or energy efficiency to flatten the summer demand spike. That will improve generation capacity factors

# Demand Near Peak Level in Very Few Hours



# Wholesale Market Changes

- Simultaneous, not sequential markets
- Feasible bids and dispatch
- Obligation to perform-as-bid for generators
- Effective market monitoring
- Consistent with regional market designs

# Additional Issues

- Robustness of our supply assessments is diminished by potential plant retirements
- Retail rates: What it will all cost and who will pay
- Demand responsiveness programs are capacity resources, too
- Current *ad hoc* market arrangements have halted progress in renewable generation development
- New power plants: Everyone wants one, but there are *real* siting constraints

# Plant Life Management Defined

- Power plant life management
  - physical and operational changes made by the owner over the life of the plant in reaction to changing economic and regulatory circumstances

- Such changes can range from
  - a complete replacement of the old plant,
  - a repowering to increase its capacity,
  - refurbishing it to maintain its current operating levels
  - letting some performance deterioration occur,
  - putting it in short-term or long-term standby reserve (mothballing)
  - or even retiring the plant.

# Purpose of PLM Assessment

- Immediately, to encourage comments on our proposed screening analysis methodology
- Ultimately, to make our supply/demand balance assessment more robust
- And possibly, to identify opportunities where public benefits could be enhanced by incenting owners to consider public benefits in their PLM decisions

# Assessing Plant Life Management Options, Not Mandating Retirements

- State policies supporting energy efficiency and demand responsiveness, and generation from renewable sources and advanced gas-fired turbines are based, at least in part, on achieving fuel use savings and emissions reductions associated with economic displacement of "dirty old plants"
- But, California hasn't mandated retirements for "purely" public benefit reasons over the economic interests of owners
- Instead, California allowed power plants to maximize the economic benefit of their owners *within regulatory constraints* to protect public health, the environment and system reliability (public safety)?

# Why Not Mandate Retirements?

- Even units targeted for reduced usage still provide valuable public benefits.
  - to maintain local system reliability and voltage support
  - to mitigate locational market power
  - to moderate the price of ancillary services
  - to avoid the cost of prohibitively expensive alternatives
  - to provide a capacity reserve (insurance against extreme demand peaks driven by unusually high temperatures or against severely reduced generating supplies from drought conditions or large simultaneous maintenance and forced outages of generation and transmission facilities)

# A Complete PLM Assessment Would Mean:

- Taking comments on a proposed screening methodology
- Taking public input on weighting factors and their policy implications
- Performing a screening analyses using scenarios and sensitivities (of different attributes and weights)
- Identifying the most robust set of PLM candidates
- Closely investigating the costs, benefits and risks resulting from the retirement or reconfiguration of *individual* units
- Negotiating mutually agreeable outcomes

# Selecting Performance Criteria

- System reliability reliability-related criteria:
  - forced outage rate
  - capacity factor
  - maintenance outage rate
  - dependable capacity
  - plant age
  - possession of a reliability-must-run (RMR) contract with the ISO
  - location of the plant in a generation-deficient or transmission-constrained area
- Environmental criteria:
  - cooling method used
  - water source
  - $NO_x$ emissions

# Valuing: Weighting the Criteria

- Each factor would be given a weight and each power plant unit would end up with a weighted value for each factor
- The weighted values for all factors would then be combined into a score for the unit
- Because their roles differ in meeting load in the bulk power market, staff would compare utility boilers, gas and oil turbines, and combined cycle units separately
- Once grouped together, the individual power plant units would be ranked according to their individual unit total scores
- The poorest ranking units would be the best candidates for the next stage of the evaluation--the detailed, site-specific evaluation of the costs, benefits and risks resulting from the retirement or reconfiguration of individual units.

# PLM Intervention

- If performance the State values isn't expected under current conditions, the State may:
  - do nothing
  - change the constraint
  - provide incentives to change performance
- Reliability, public health and environmental effects of power plants are complex and dynamic. Site-specific analysis of the costs and benefits of alternative means is needed to:
  - ensure the action achieves its goal
  - avoid negative unintended consequences
- If benefits exceed the costs, and there are no alternatives to achieve the same level of benefit either more directly or at lower cost, then an incentive may be warranted.

# Possible Screening Results

- If a unit generates adverse environmental impacts, but makes a contribution to reliability, then the State may offer incentives to encourage the owner to apply controls to mitigate such impacts.

- If a unit rates poorly with respect to reliability (has little reliability value to the system) but does not have a significant environmental impacts, then the State may be content to let economic displacement of the unit diminish its use over time.

- A unit performs poorly on both environmental and reliability criteria but still have value to the owner. If the State had an additional interest to see the unit retired external to the interests of the owner, the State may offer incentives to the owner. Or it may be preferable that market forces effect the economic displacement of the unit.

# Retail Rate Outlook

- Retail electricity rates that typical consumers *may* pay, given projected energy prices, utility plans and programs, and regulatory decisions
- Provide consumers, market participants and policy makers with a basic understanding of future electricity rates.
- Future regulatory actions, technology development, or market changes may alter key fundamental assumptions.

# What's It Cost to Provide Electricity?

Nominal $ (millions)

| **IOUs** | 2002 | 2005 |
|---|---|---|
| Sales GWh | 204,233 | 229,444 |
| Generation Expenses | $ 18,119 | $ 19,282 |
| Non Generation | $ 9,185 | $ 12,867 |
| Total | $ 27,304 | $ 32,149 |

| **MUNIS** | 2002 | 2005 |
|---|---|---|
| Sales GWh | 35,336 | 38,524 |
| Generation Expenses | $ 2,949 | $ 3,514 |
| Non Generation | $ 556 | $ 671 |
| Total | $ 3,505 | $ 4,184 |

| **GRAND TOTAL** | $ 30,810 | $ 36,334 |
|---|---|---|

# Who Pays?

Estimated Expenditures
2002 and 2005
Nominal $ (millions)

| | IOUs | | | MUNIS | | |
|---|---|---|---|---|---|---|
| | 2001 | 2002 | 2005 | 2001 | 2002 | 2005 |
| **Residential** | | | | | | |
| Sales GWh | 60,143 | 62,706 | 69,077 | 11,603 | 12,025 | 13,008 |
| Expenditures (million) | $ 8,332 | $ 8,090 | $ 9,458 | $ 1,190 | $ 1,223 | $ 1,441 |
| **Small Commercial** | | | | | | |
| Sales GWh | 41,712 | 43,638 | 50,231 | 8,380 | 8,761 | 9,621 |
| Expenditures (million) | $ 7,942 | $ 7,689 | $ 8,833 | $ 913 | $ 949 | $ 1,144 |
| **Medium Commercial** | | | | | | |
| Sales GWh | 41,712 | 43,638 | 50,231 | 8,380 | 8,761 | 9,621 |
| Expenditures (million) | $ 5,983 | $ 5,748 | $ 7,189 | $ 815 | $ 846 | $ 1,018 |
| **Industrial** | | | | | | |
| Sales GWh | 41,892 | 43,336 | 48,117 | 5,402 | 5,615 | 6,082 |
| Expenditures (million) | $ 4,632 | $ 4,341 | $ 5,014 | $ 455 | $ 471 | $ 562 |
| **Agricultural** | | | | | | |
| Sales GWh | 10,514 | 10,915 | 11,788 | 167 | 175 | 192 |
| Expenditures (million) | $ 1,532 | $ 1,436 | $ 1,656 | $ 16 | $ 16 | $ 19 |
| **Total** | | | | | | |
| Sales GWh | 195,974 | 204,233 | 229,444 | 33,932 | 35,336 | 38,524 |
| Expenditures (million) | $ 28,421 | $ 27,304 | $ 32,149 | $ 3,389 | $ 3,505 | $ 4,184 |

# How's that translate into rates?

**Table ES-1**
**System Average Electricity Rates in Cents per kWh ($2001)**

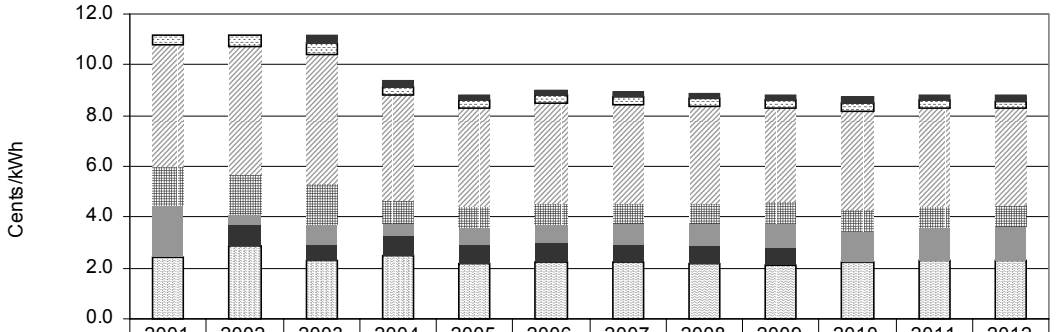
| Year | PG&E | SCE | SDG&E | LADWP | SMUD | Burbank | Pasadena | Glendale | GDP Deflator |
|---|---|---|---|---|---|---|---|---|---|
| 2002 | 10.5 | 13.8 | 13.2 | 9.6 | 8.9 | 11.8 | 11.7 | 11.8 | 103.0 |
| 2003 | 12.4 | 14.0 | 13.5 | 9.4 | 8.7 | 11.6 | 11.4 | 11.5 | 105.5 |
| 2004 | 11.8 | 14.5 | 12.9 | 9.6 | 8.3 | 11.9 | 11.7 | 11.8 | 108.3 |
| 2005 | 11.9 | 13.7 | 12.6 | 9.9 | 8.5 | 12.3 | 12.0 | 12.2 | 111.2 |
| 2006 | 12.0 | 13.6 | 12.9 | 10.2 | 8.8 | 12.6 | 12.4 | 12.5 | 114.0 |
| 2007 | 11.8 | 13.3 | 12.6 | 10.5 | 9.1 | 12.8 | 12.8 | 12.9 | 116.9 |
| 2008 | 11.2 | 12.7 | 11.9 | 10.8 | 9.3 | 13.0 | 13.1 | 13.2 | 119.6 |
| 2009 | 10.9 | 12.4 | 11.7 | 11.2 | 9.7 | 13.2 | 13.6 | 13.7 | 123.7 |
| 2010 | 10.7 | 12.1 | 11.4 | 11.6 | 10.0 | 13.4 | 14.0 | 14.1 | 127.4 |
| 2011 | 10.6 | 11.9 | 11.3 | 12.9 | 10.4 | 13.6 | 13.9 | 14.6 | 131.5 |
| 2012 | 10.4 | 11.6 | 11.0 | 12.4 | 10.9 | 13.7 | 13.7 | 15.1 | 135.7 |

# Summary of Results

- Under the current circumstances, retail rates for IOU customers will most likely increase in the 2002-2003 period.
  - In 2003 IOU rates average 13.4 cents/kwh
  - while Municipal rates average 10.3 cents/kwh in 2003

- Although rates for IOU customers are generally higher than rates for the larger municipal utility customers in the initial years, they become comparable in the later years.

# Much of the Cost Already Incurred




| | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Utility Debt | 0.0 | 0.0 | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Other Utility Contracts | 0.4 | 0.4 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Utility QF Contracts | 4.7 | 5.0 | 5.1 | 4.2 | 3.9 | 3.9 | 3.9 | 3.8 | 3.7 | 3.9 | 3.9 | 3.8 |
| Utility Plants | 1.5 | 1.6 | 1.6 | 0.9 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Spot Market | 2.1 | 0.4 | 0.7 | 0.5 | 0.6 | 0.7 | 0.8 | 0.9 | 1.0 | 1.2 | 1.3 | 1.4 |
| DWR Financing | 0.0 | 0.8 | 0.6 | 0.8 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.0 | 0.0 | 0.0 |
| DWR Contract | 2.4 | 2.9 | 2.3 | 2.5 | 2.2 | 2.2 | 2.2 | 2.2 | 2.1 | 2.2 | 2.3 | 2.3 |

- For example, Edison's Average System Rate in 2003 is 14.02 cents/kWh
- Of that, 11.2 cents/kWh is generation related (shown in detail above), and only 0.7 cents of that is spot market related

# More Detailed Results

- Average electricity rates for IOU small commercial customers could reach up to 19 and 20 cents/kWh in 2003

- Energy generation costs reflected in the rates of residential customers of PG&E, Edison and SDG&E amounts to approximately 50 percent of the rate. However, for medium commercial and industrial, it can account for up to 80 percent of the rate.

# Future Rate Uncertainty

- Future electricity rates for the IOUs depend more on
  - regulatory decisions of the Federal Energy Regulatory Commission (FERC), State Legislature, the Governor, and the CPUC
  - rather than the spot market prices

- Since municipal utilities have long-term contracts for energy, their future electricity rates depend more on
  - the price of natural gas
  - the need to replenish their rate stabilization funds.

# Demand Response Is A Supply Option

- California is likely to have sufficient resources to cover load and supply contingencies for normal weather in 2002-2004.
- But extreme weather, especially Westwide, could make the supply/demand balance tight
- What is the best mix of new generating capacity and demand response to cover these unusual conditions?

# Demand Response vs Peakers

- Up to 5,000 MW of load can be expected for less than 200 hours per year
- This is the typical duty cycle of combustion turbines
- Demand responsiveness offers an alternative to new power plant peaking capacity

# Demand Response Evaluation Criteria

- Economic Efficiency - reduces customer cost of outages
- Market Prices - can reduce market clearing prices
- Planning Uncertainty - funding mechanisms
- Operating Uncertainty - what reductions will actually occur?
- Flexibility - shorter capital cost recovery
- Secondary Benefits/Costs - transition step to real-time pricing

# Status of Demand Response Strategy

- Program design and funding authority among agencies is in “total disarray”
- CPUC has launched Phase 2 of R.00-10-002 addressing UDC programs for “2002 and beyond”
- RTP tariff designs have been filed with CPUC
- 13,000 MW of load will have RTP metering systems

# Staff Recommendations

- 2,500 MW of planned demand responsiveness capability should be obtained from load curtailments and tariffs
  - 1,000 MW of this has already been proposed as modifications to two CPUC-approved load curtailment programs
  - Big enough number to offer a variety of programs and tariffs
  - Committing to a mixture of demand response and new capacity provides flexibility

# Renewable Generation Issues

- Developers of new renewable energy projects currently face a high degree of uncertainty
- The biggest impediment to further development of renewable projects is the lack of a stable market with buyers willing to provide adequate price certainty

# Adverse Conditions for Renewables

- Potential buyers of renewable resources are few
  - Direct access is closed to new customers
  - A Renewable Portfolio Standard was proposed but not passed last legislative session
  - The Department of Water Resources has purchased only limited amounts of renewable generation and has already purchased enough power to meet most of its needs
  - The investor-owned utilities are undergoing financial difficulties

# Is Help on The Horizon?

- Legislation has extended the Energy Commission's renewables program, but some new renewable generation funded through the Energy Commission's auctions may never get built due to the current uncertainty over who will buy this generation
- The Power Authority has announced its intentions to negotiate with renewable generators, but has made no firm commitments to buy renewable generation
- Generators do not know whether they may be selling to meet a new Renewable Portfolio Standard or to a revitalized renewables-only direct access market

# Licensing Power Plants During the Crisis

- Energy Commission's efforts during the electricity emergency helped bring new capacity on line by the summer of 2001
  - conditioned licensing of new power projects
  - conducting early site screening for emergency projects
  - assisting developers with project compliance amendments
  - assisting developers with roadblocks to completing construction

# Licensing Constraints

- Environmental and permitting issues constrain the amount of new capacity additions that can be licensed
  - availability of emission offsets
  - water supply and water quality impacts
  - the timing of federal permits
  - land use conflicts
  - transmission congestion
  - and natural gas supply constraints
- Not enforcing these constraints can result result in contested proceedings or potentially significant adverse impacts.

# Planning Coordination

- The Energy Commission has previously supported consolidation of transmission line permitting in California.
  - Energy Commission licenses transmission lines that interconnect to power plants under its review
  - other transmission projects are permitted by multiple agencies
- The Energy Commission should support efforts to develop a state planning effort for new generation and transmission lines to address
  - congestion
  - system reliability, and
  - efficiency issues.